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Of Blabbermouths and Tattletales; The Life and Times of Automatic Line Leak Detectors

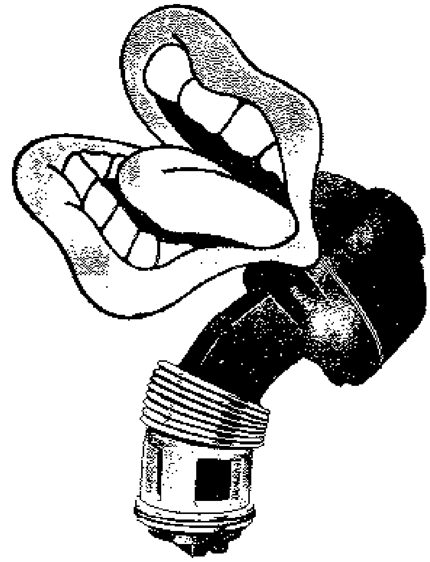
Automatic Line Leak Detectors = Devices that alert the operator to the presence of a leak by restricting or shutting off the flow of a substance through piping or by triggering an audible or visual alarm. According to the federal rule [40 CFR 280.44(a)], a device used to meet this requirement must detect leaks of 3 gallons per hour at 10 pounds per square inch line pressure within 1 hour. An annual test of the operation of the leak detector must be conducted in accordance with the manufacturer's requirements.

<u>An Antidote to Pressurized Piping Leaks</u>

With a history going back to the late 1950s, the automatic line leak detector (ALLD) is probably the grandmother of all the "continuous" type of leak detection devices on the market today. ALLDs were developed not too long after submersible pumps began to be commonly used -- an indication, perhaps, that the increasing use of pressure rather than suction to move product from underground tanks into motor vehicles had intensified the severity of piping leaks.

While line leaks in suction pumping systems certainly existed, they tended to be self-limiting; if the leak got too bad, the pump would cease to function. Even small leaks would cause noticeable interference with the fuel delivery operation and thereby alert the operator.

Although pressurized pumping systems had operational advantages, such as simplified piping and the absence of vapor lock (see *LUSTLine*



#10, "Pumping Product-The Push Ups vs Pull Ups of Product Delivery Systems-Implications for Environmental Health"), they had a definite downside in terms of leaks. Because the piping operated under 25 to 30 pounds of pressure, leak rates from even small holes increased substantially over those in suction pumping systems. To compound the problem, there were

(Continued on page 2)

Inside This Issue

Testing In-Line Leak Detectors

Several installers have recently inquired about proper testing methods for in-line leak detectors. The question has been whether the test should be qualitative, such as the catastrophic test, or quantitative where the device is calibrated to a three (3) gallon per hour simulated leak. Specifically, Chapter 691, Section 5.D(6) states:

> "Operation, maintenance and testing of in-line leak detectors. In-line leak detection devices must be maintained to properly operate in accordance with this rule at all times while the piping contains oil. All in-line leak detectors must be tested for proper operation in accordance with manufacturer instructions upon installation and at least once each calendar year thereafter. Test of in-line leak detectors must be conducted by a manufacturer trained representative of the owner, qualified tank testing professional or a certified underground tank installer. Improperly operating leak detectors must be repaired or replaced by a certified underground tank installer, the manufacturer's representative or manufacturer trained representative of the owner within 30 days. A log of all tests, maintenance, and repairs must be maintained by the owner at the facility or the owner's place of business for a period of at least 3 years."

In the past, there were only a limited number of manufacturers of mechanical in-line leak detectors. At that time the Environmental Protection Agency, as well as the Department, interpreted the phrase "in accordance with manufacturer instructions" to mean that either the manufacturer's qualitative or quantitative test was allowable. The idea was that once an in-line leak detector passed an initial three (3) gallon per hour test it would remain properly calibrated for the life of the device. This, however, has

(Continued on page 2)

The Life and Times of Automatic Line Leak Detectors

(Continued from page 1)

no indications of a problem at the dispenser, so the operator had no way of knowing (except through inventory control) that there might be a piping leak.

Following the popular acceptance of the submersible pumping system, the industry developed a device that would automatically detect leaks in pressurized pumping systems. In one early ad, this new device was dubbed the "blabbermouth" because it would quickly "snitch" on a leaking pipe.

Over the years, a few refinements to the leak detector were introduced that shortened the time it took to complete the test of the piping from 5 seconds to 2 and added a chamber to help compensate for thermal contraction effects, but the basic operation of the mechanical device has remained unchanged to this day.

Meanwhile, back at the fire station, the fire codes recognized the potential hazards posed by pressurized piping systems and began mandating the use of line leak detectors long before they became an EPA requirement. The codes included a requirement that the devices be tested at least annually to ensure that they were functioning properly. Despite this requirement, ALLDs were often absent from pressurized pumps; most owner/ operators did not test for proper operation on an annual basis. The inclusion of these requirements in the federal rule, however, resulted in significantly increased use of ALLDs ... and many are even tested on an annual basis.

The Mechanics of a MALLD

The mechanical ALLD (MALLD) is basically a pressure-operated valve. The top of the MALLD contains a piston or diaphragm that is connected to a rod that controls the flow of product by operating a valve mechanism at the bottom of the device. The valve has three positions: wide open (full flow), test (flow limited to 3 gallons per hour), and restricted flow or "tripped" position (flow limited to 3 gallons per minute).

A spring inside the stem of the MALLD pushes down on the control rod, continually attempting to move the valve into the restricted flow position. Pressure produced by liquid in the piping system pushes against the piston or diaphragm inside the top of the MALLD, compressing the spring and keeping the valve open. Inside the MALLD, there is a continual tug-of-war going on between the spring that wants to close the valve and the liquid pressure that wants to keep the valve open. Let's look at who wins this tug-of-war under various operating conditions.

What happens when all is well?

In a pressurized piping system, the pump develops about 25-30 pounds per square inch when it is operating and delivering fuel. When the pump motor is turned off, pressure in the line is reduced to the "catch" pressure of a pressure relief valve that is incorporated in the submersible pump. If the piping is tight, the catch pressure is maintained in the pipe until the pump is turned on again. In this case, the liquid pressure wins the tug-of-war, the spring stays compressed, and the valve remains open.

What happens when there is a leak?

In a leaking pressurized piping system, the pressure in the piping will continue to drop below the pressure relief valve "catch" pressure as product

(Continued on page 3)

Testing In-Line Leak Detectors

(Continued from page 1)

proved to be incorrect, and today several manufacturers of mechanical and electronic in-line leak detectors require annual three (3) gallon per hour qualitative test. In addition, Chapter 691, Appendix E, Section 7 states:

> "Product supply lines used in conjunction with pressurized pumping systems must be installed with a product line leak detection device. All leak detection devices must be tested for proper operation before the remote pumping system is used after initial installation and once annually thereafter. All leak detectors must be capable of detecting a leak at a rate of at least 3 gallons per hour at a line pressure of 10 psi within one hour of occurrence with a 95 percent probability of detection and a 5 percent probability of false alarm."

Appendix E gives clearly states that **all in-line leak detectors** must be able to meet the 3 gallon per hour criteria for the life of the device and therefore requires an annual quantitative test using the three (3) gallon per hour simulated leak test.

I hope this clarifies what has been in the past a confusing issue.

David McCaskill, P.E., Division of Technical Services, Bureau of Remediation and Waste Management, Maine Department of Environmental Protection.

The Life and Times of Automatic Line Leak Detectors

(Continued from page 2)

leaks out of the piping. The rate of pressure decline depends on the size of the hole, but it is also a function of how rigid the piping system is. A steel piping system is quite rigid, so a small loss of liquid from inside the pipe will produce a large pressure drop.

Flexible piping systems are generally much more "stretchy" than steel. As the flexible piping is pressurized, it stretches, and as pressure is reduced, the flexible piping tends to contract-much the same way (although to a lesser degree) as a balloon expands when air is blown in and contracts when air is removed. When liquid leaks out of flexible piping, the piping contracts somewhat, maintaining some of the pressure in the pipe.

Thus, for a given leak rate, the pressure will drop precipitously in steel piping and more slowly in flexible piping. The point is, however, in both cases the pressure will drop to very low levels if the piping is not liquid-tight. This sets the stage for the spring to win the tug-of-war and move the valve mechanism to the restricted flow position.

How the MALLD responds...

When the pressure in the piping drops below a threshold pressure, the spring in the MALLD takes control and moves the valve past the test position and into the restricted-flow position. Different manufacturers of MALLDs have different threshold pressures, but they are all in the range of a few pounds.

The MALLD stays in this restricted-flow, or "tripped," position, waiting for the next customer to come along and turn on the pump. When the pump is turned on, the flow through the MALLD is restricted to about 3 gallons per minute. Unless there is a leak in the piping that is greater than 3 gallons per minute, this flow into the piping system will increase the pressure in the line. This increase in pressure will press against the piston or diaphragm of the leak detector and begin to move the control rod that activates the valve mechanism. At about 10 pounds per square inch of pressure in the line, the control rod will have moved the valve mechanism into the "test" position. In the test position, the flow into the piping system is reduced dramatically to 3 gallons per hour.

... To a false alarm.

If the leak detector has been tripped because of a false alarm (see below) and the piping is tight, this small flow of liquid into the piping will continue to increase the pressure in the line. At a few additional pounds of pressure, the valve mechanism moves past the test position and into the wide-open position, where the dispensing of product can proceed unimpeded. The time required to go from the tripped position through the test cycle and into the open position is about 2 seconds.

... To a leak of 3 gallons per hour or more.

If the piping has a leak of greater than 3 gallons per hour, the 3 gallons per hour of liquid flowing past the leak detector into the piping will flow out of the pipe as fast as it is coming in. The pressure in the piping will not increase, and so the valve mechanism will not move out of the 3-gallons-per-hour test position.

Now, keeping in mind that the reason the pump was turned on in the first place was to dispense fuel, we turn to the customer, who opens the nozzle in anticipation of pumping some product at a flow rate of 10 gallons per minute. If the leak detector is still in the test position, however, this will not happen. With the nozzle open, whatever pressure was in the piping is now lost, the leak detector valve returns to its restricted-flow position, and the customer receives a flow of 3 gallons per minute. It is this reduced flow rate that is supposed to be noticed by the customer and reported to the station attendant (assuming a self-service type of operation).

... To smaller leaks.

For leaks of less than 3 gallons per hour or for flexible piping systems, the time required for the leak detector to go through the test phase and reach the wide-open flow position will be longer than 2 seconds. But if enough time is allowed, the piping should be able to build enough pressure to move the leak detector into the wide-open flow position. Whether a customer experiences restricted flow will depend on the length of time between when the pump is turned on and when the customer opens the nozzle.

A Few Rubs

A number of factors can cause MALLDs to restrict flow when a leak is not present (i.e.,false alarm):

Malfunctioning check valves

The valve mechanism in the submersible pump that retains product in the line between the times when customers pump product can leak. This is not a leak into the environment; rather, the product merely returns to the underground tank. The loss of product in the line, however, will cause the leak detector to trip, and it may take many seconds to refill the line, greatly increasing the likelihood that the customer will have opened the nozzle and, thereby, set the MALLD in the restricted flow position.

Thermal contraction

In cold climates, the ground temperature around the piping is often significantly colder than the ground temperature around the tank. As a result, relatively warm product flows into the piping. When it is allowed to sit, especially overnight, it cools and contracts. This reduction in temperature can reduce the pressure in the line and trip the ALLD.

Air pockets

Air pockets in the piping introduce "springiness" into the piping system, because the air is very compressible. As a result, it will take more product (and therefore longer time) for the MALLD

The Life and Times of Automatic Line Leak Detectors

(Continued from page 3)

to move from the tripped to the open position.

There are also some factors that can cause MALLDs to miss leaks:

Excessive height of the piping

In order to move into the tripped position, the pressure at the MALLD must drop to a threshold pressure that can be as low as 1 pound per square inch. A column of product about 3 feet high is sufficient to produce a pressure of about 1 pound per square inch at the bottom of the column.

Let's say, for example, there is a 4-foot height differential between the MALLD and the dispenser shear valve. In order for the MALLD to trip and conduct a leak test, the height of the product would have to drop about 1 foot below grade. If the leak is at the shear valve, however, the piping below the shear valve will remain full of product, the hydrostatic pressure at the MALLD will never go below the trip pressure, and the leak will never be detected. In the old days, deep burial of tanks was quite uncommon, but now that we are paying more attention to piping slope, particularly with Stage II piping, MALLD burial depths can sometimes be well below 3 feet.

Mechanical wear

The tolerances in the valve mechanism of the MALLD are quite fine, but as the device wears, these tolerances tend to become less fine (i.e., greater). The result is that as the MALLD ages, the minimum size leak that it will detect tends to increase.

Sticking

Because the MALLD is mechanical, it relies on the physical movement of parts to detect the leak. If piping is tight and pressure is always maintained in the line, the mechanism of the MALLD may move little or not at all for months or even years on end. Deposits can build up on moving parts, tending to lock them in place. The result is that when a leak does develop, the MALLD fails to respond.

Satellite dispensers

In this era of self-serve gasoline dispensing, there is a remotely operated solenoid valve located in the dispensers and controlled by the cashier. This valve is often programmed to remain closed until after the MALLD has completed its test to prevent false alarm when a customer opens the nozzle while the MALLD is still looking for leaks. As a result, leaks downstream of the solenoid valve are invisible to the MALLD. In normal dispensers, such "invisible" leaks are not a big problem, because all of this piping is above ground, and leaks can be discovered visually.

However, many large truck fueling facilities have what are known as satellite dispensers that allow the driver to fuel tanks on both sides of the truck at the same time. The satellite dispenser is essentially another hose that is routed from the master dispenser to a nozzle about a dozen feet away. The routing of this "hose" is typically underground, and typical piping materials (e.g., FRP, flexible pipe) are used.

In older model satellite dispensing systems, the piping that branches off to the satellite dispenser is typically downstream of the solenoid valve. Because of this, leaks in piping that goes to the satellite dispenser are not detected by the MALLD. A possible solution to this problem is to add a dispenser-mounted electronic line leak detector to monitor just the satellite piping.

Newer model master/satellite dispensers incorporate two solenoids -- one in the master and one in the satellite. In this configuration, the satellite piping branches off from the master dispenser at a point that is upstream of the solenoid in the master dispenser. This dual solenoid system does allow the satellite piping to be tested by the line leak detector.

Lack of pump cycling

In the vast majority of fueling facilities, the pump motor is turned off most of the time and operates only while fuel is being dispensed. This cycling of the pump motor is essential to the operation of the MALLD. However, there are a few facilities that I've heard about where, for various reasons, the pump motor is on continuously for long stretches of time. At this type of facility, the MALLD fails to meet the regulatory criteria for detecting a leak within 1 hour, because the pump may be on continuously for days or weeks; until the pump is turned off and then restarted, any leak of any magnitude will not be detected by the MALLD.

The human element

Historically, the restriction of flow produced by the leak detector was often dismissed as a problem with the leak detector, because the problem went away when the leak detector was removed (and, all too often, not replaced). Even today, knowledge of the meaning of restricted flow rates is not universal.

For example, I was fueling up in northern New Mexico not too long ago and noted that it took a very long time to complete my purchase. When I mentioned this to the attendant, his response was, "Oh yeah, that pump always runs slow." Admittedly, clogged fuel filters in dispensers, malfunctioning pumps, and partially closed shear valves can all produce symptoms of restricted flow, so this condition is not a conclusive indication of a leak, but it is also not a condition that should be accepted as normal.

<u>The Electronics of EALLDs</u>

Over the past decade, the emphasis on leak detection in piping created by the federal rule has spurred the development of a new breed of line leak detectors that are electronically, rather than mechanically, based. This new breed of electronic

(Continued on page 5)

The Life and Times of Automatic Line Leak Detectors

automatic line leak detectors (EALLDS) usually incorporates a microprocessor to enable the EALLD to make more informed decisions about the data that it is receiving as well as to run more sensitive tests on the piping. Typically, but not always, EALLDs control power to the pump. Very often, the EALLD microprocessor is incorporated into an automatic tank gauge console.

Most EALLDs use a pressure transducer (a device that converts changes in pressure to variations in voltage) to monitor pressure in the piping. Except for the fact that both MALLDs and EALLDs monitor pressure in the piping, they have little else in common. The EALLD usually checks for a leak after the pump motor has been turned off. As with MALLDS, when the pump motor is turned off, the pressure in the piping is allowed to drop to some "catch" pressure determined by the pump's pressure relief mechanism. The EALLD then monitors the pressure in the system to see if there is a continuing precipitous drop in pressure. If such a pressure drop is detected, most devices will cut off the pump power and not allow power to be restored by the mere push of a button. A knowledgeable technician must reset the unit to restore power to the pump, presumably after he or she has determined the cause of the pressure drop.

This leak detection feature of the EALLD is fairly straightforward and works well as long we are looking for a leak in the 3 gallons per hour range. However, in addition to 3-gallon-per-hour tests, many EALLDs also have the ability to conduct 0.2-gallon-perhour and sometimes even 0.1-gallon-per-hour tests. Leak detection at this level is somewhat more challenging because of thermal effects, piping resiliency, air pockets, and the effectiveness of system hardware such as check valves -- but that discussion will have to wait until another issue *of LUSTLine*.

There are a few EALLDs that work on a slightly different principle-by taking over control of the pump motor and leaving the pump motor running for a brief period after the fuel dispensing operation is completed. With the piping system at operating pressure, an electrically controlled valve near the pump closes and a small alternate flow path from the pump side of the valve to the dispenser side of the valve opens. As long as the pressure on both sides of the closed valve is equal, there will be no flow through the alternate flow path. However, a hole in the piping on the dispenser side of the valve will cause the pressure to drop, thus allowing product to flow through the alternate flow path. The flow rate is then measured, and if it exceeds the threshold leak rate for the device, a leak is declared.

The new breed of electronic automatic line leak detectors (EALLDS) usually incorporates a microprocessor to enable the EALLD to make more informed decisions about the data that it is receiving as well as to run more sensitive tests on the piping.

Several EALLDs incorporate “wireless” technology to transmit information from the pressure or flow sensor located near the pump to a control unit that is typically located near the pump power supply. This means that the sensor signal is sent through the same wires used to power the pump, thus avoiding the cost of running new wires for the EALLD. A number of EALLD devices can also be installed in the same opening as was used for a MALLD. These features make retrofit of EALLD on existing installations relatively straightforward.

Keep in mind that the UST rules do not distinguish between MALLD and EALLD with regard to annual testing. Whatever device is used to meet the 3-gallon-per-hour leak detection requirement must be tested annually for operation according to manufacturer's instructions.

A Few Rubs

EALLDs have their own problems when it comes to software. Most EALLDs complete a 3-gallon-per-hour leak test in a matter of seconds after the pump is turned off. I am aware of at least one model, however, that requires three consecutive failed tests conducted at 5-minute intervals before declaring that piping is leaking. Thus, the detection of a leak requires a minimum of 10 minutes, during which no fuel can be dispensed. To meet the regulatory standard of detecting a leak within 1 hour, this device would require 10 minutes with no fuel dispensing every hour. There are a good many facilities where 10 minutes of downtime will happen only in the wee hours of the night. It seems to me that devices such as this one do not meet the standard for ALLDs set by the federal rule.

Note that EALLDs work when a pump is cycled from on to off, as opposed to MALLDs that test the piping when the pump is cycled from off to on. EALLDs still require that the pump be cycled to conduct a test and do not meet regulatory requirements on systems where the pump motor is on all or most of the time.

EALLDs have the same issues as MALLDs with regard to satellite dispensers. Pressure-based EALLDs may have false alarms from malfunctioning check valves, and flow-based EALLDs have moving parts that can get clogged, but the other problems mentioned above with MALLDs have largely been overcome.

Future ALLDs

After several decades of stability, ALLDs have experienced an explosion of technical development since the emergence of the federal rule. These developments are continuing with the introduction of more sophisticated

(Continued on page 12)

Command and Control of Vapors at UST Work Sites

Within one week, last December in California, explosions occurred inside tanks at two different locations. When all was said and done, one worker had died and three had suffered severe burns. Tank accidents happen. They shouldn't. They needn't. But they do. They happen when people are in a hurry and cut corners, or when site conditions change and the hazards are not recognized.

Despite the obvious potential for death from explosion, severe burns, petroleum or other chemical exposure, physical injury from heavy equipment, and lacerations and contusions from flying metal parts, many people who work around tanks do not, or do not want to, recognize the ever-present potential for danger. But tank-related accidents and near misses do, in fact, occur, and they occur all too often. Unfortunately, there is no system for recording and maintaining records of the number of tank-related accidents, deaths, or injuries in the United States.

The 1998 deadline will certainly add to the pressure on UST contractors and inspectors. For this reason, it will be even more critical for workers to be properly trained, to have adequate supervision, and to follow safe procedures. In my experience, most accidents occur because of poor control of vapors combined with the introduction of ignition sources. In this article, I'll discuss the safe handling of USTs and control of vapors during removal operations.

OSHA Says...

The California explosions resulted in Occupational Safety and Health Administration (OSHA) citations that illustrate the hazards that exist on UST sites when safety procedures are bypassed in order to save time. In both accidents, the tanks had not been purged of flammable vapors prior to work, the atmosphere inside the tanks had not been tested, and ignition sources had been introduced inside the tanks. In addition, both accidents involved tank lining operations, and some of the workers were actually in the tanks at the time of the explosions. Jobs such as tank cleaning, lining, and interior inspection involve a number of physical hazards in addition to the health effects from flammable liquids.

Since 1987, OSHA has required that anyone working on a hazardous waste site have health and safety training. These requirements involve 40 hours of initial training and an annual 8-hour refresher course. Hazardous waste sites include UST removal operations and corrective actions that involve tanks that contain or have contained chemicals or petroleum products. For certain types of tank work, OSHA's confined-space entry standard may apply. This standard also includes the training of workers and supervisors, if they are to enter a tank.

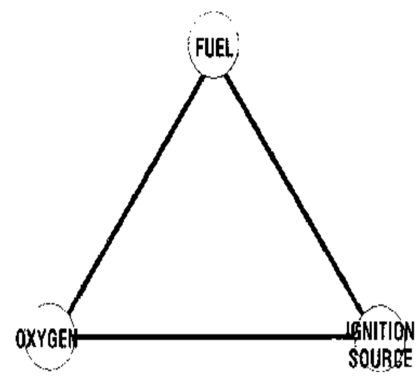
These OSHA regulations apply regardless of the type of chemical or petroleum contained in the tank. Products such as #2 fuel or diesel and heavy fuels such as #4, #5, or #6 may not be as flammable as gasoline, but they still constitute a health risk and, hence, require health and safety training.

The Fire Triangle

In order to create a fire or explosion, three elements are needed: an ignition source, fuel, and oxygen. These elements make up what is known as the "fire triangle." Let's look at each corner of the triangle.

Eliminating Ignition Sources

In tank removal, the possible presence of petroleum and chemical vapors is of paramount concern. Potential ignition sources need to be eliminated before heavy equipment is used in the vapor hazard area. Sources of ignition include heat, flame, static electricity, or any other process or equipment that produces a spark. Smoking is one of the most common sources of ignition and should



be banned on the entire work site.

It is not unusual to see workers who are between tasks, stand and

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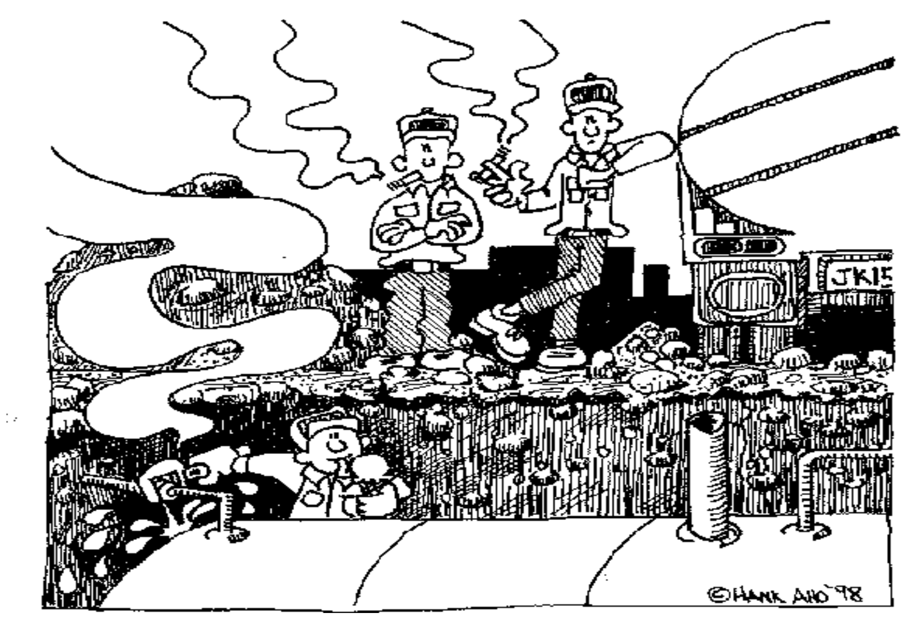


Vapors at UST Work Sites

(Continued from page 6)

smoke near a tank excavation, downwind of the vapors, seemingly oblivious to the possibility that a hazard exists. Because the odor threshold for smelling gasoline is quite low, most people can't tell the difference between high and low concentrations in the air. In addition, gasoline vapors are heavier than air and will travel along the ground to remote areas of the site or collect under vehicles and other obstructions. Turning a vehicle ignition to the "on" position or keying a two- way radio may be enough to ignite accumulated vapors. For this reason, some local ordinances require that open flames and spark-producing devices be banned within 50 feet (or more) of a vapor hazard area.

On these hazardous work sites, it is essential that any electrical equipment be "explosion-proof" -- that is to say, it should have a case that can withstand an explosion from within. Examples of such equipment are explosion-proof blowers used to vent flammable vapors out of a tank so that a worker can enter to clean it, or low-voltage or explosion-proof lighting used to illuminate work areas. Tank workers and inspectors need to use electronic equipment such as hand-held radios and air monitoring equipment that is intrinsically safe and will not create a spark while operating in the vapor hazard area. Nonsparking tools, such as those made of brass or brass-coated, need to be used to perform tasks such as detaching piping from a tank.

Static electricity is an ignition source that is often forgotten. Movement of air or compressed gas, as well as movement of liquid, in a pipe or hose can cause static. To eliminate static electricity, a conductive path to discharge the static electricity can be created by connecting both ends of the flow conduit (e.g., the hose fitting to the tank and the other end to the truck) and then grounding the mechanical device that is moving the liquid or gas.

Other sources of ignition on a tank site include smoking materials thrown by bystanders or cars passing the site. Vehicular traffic can cause static electricity if metal components touch the ground and cause a spark. Underground utilities or other metal debris in the soil can create a spark when struck with a backhoe. Frayed electrical cords on power tools or extension cords with exposed wires can also create an ignition source.

Controlling Flammable Vapors

Flammable substances have a range of concentrations that will burn when the other two elements of the fire triangle (i.e., ignition source and oxygen) are present. A sufficient concentration of vapor to cause a fire or explosion will occur only if the temperature of the substance is above its flashpoint (i.e., the temperature at which a liquid will produce sufficient flammable vapors to support combustion). For example, gasoline generates enough vapors to support combustion at any temperature above minus 43 degrees Fahrenheit, its flashpoint. Fuel oil, on the other hand, has a flashpoint between 110 to 190 degrees Fahrenheit, depending on the grade of oil.

Flammable vapors may come from a variety of sources on a tank removal site. If the tank has leaked, excavating the contaminated soil will allow fresh vapor to evolve. Often the soil will be contaminated from overfills, even if the tank did not leak. The tank itself is a source, as is the piping, even after the product is removed, because residual product remains in the pores of the metal, causing the tank and piping to regenerate vapors over time. These vapors can accumulate to potentially explosive concentrations within the confined space of a tank or piping.

If not properly positioned, the vacuum truck used to remove residual product and vapor from the tank can also add a significant amount of vapor to the site. This potential build-up of vapors is particularly true if the flammable vapors are vented at ground level or if they are vented beneath an obstruction such as the pump canopy.

In general, the industry standard is to vent the vapors at least 12 feet above grade and at least 3 feet above adjacent structures. Some states have mandated these standards. If vapors are not properly vented and/or tall structures surround the site, the amount of vapor

(Continued on page 8)

So, Who's Responsible for Vapors Anyway?

A common practice for gasoline tank removals in Maine involves the installer subcontracting for tank purging and cleaning to a firm specializing in this work. In doing so, a number of installers mistakeningly assume they've been able to "contract out" their responsibility for site safety. Neither legislative history nor precedent by the Board of Underground Storage Tank Installers supports such an interpretation.

The legislative history of the requirement for having installers in charge of tank removal where flammable liquids have been stored has its basis in responding to a fatal accident that occurred in Portland in 1987, where vapor buildup on site caused an explosion that killed one worker and seriously injured another. In instituting the requirement for installers to be present in the first place, the Legislature's intent was clearly to have installers responsible for site safety.

In at least two recent cases before the Board, installers who experienced fires at their sites attempted to argue that site safety was being handled by the tank cleaning contractor. In both cases, those arguments failed.

Vapors at UST Work Sites

at ground level may accumulate within the flammable range of the chemical or petroleum product. Any ignition source introduced to the site may then cause an explosion.

Vapor hazards are often made worse by poor work practices that allow fresh product to be introduced into the soil on the tank site. This occurs when pipes are not properly drained prior to removal or when a tank with residual product is further damaged by the backhoe. Time pressure to finish the operation is often the cause of these incidents.

Purging and lnerting Vapors

Control of vapor sources from the tank itself is accomplished by purging or inerting the tank. This procedure varies depending on state or local codes or on local tradition. A few states, including Maine, allow tanks to be removed while they are "overrich" (i.e., when vapor levels exceed the upper explosive limit; see LEL discussion below). This practice is not recommended but is becoming more common as the 1998 tank removal deadline looms.

Purging involves ventilating the tank and diluting the flammable vapors with air. This procedure reduces the fuel component of the fire triangle. Even though the oxygen and ignition components may still be present, fire or explosion will not occur. The two common methods of purging involve the use of a diffused-air blower or an eductor-type air mover. Either method requires bonding the pipe to prevent static buildup. It is important to always remember that purging is a *temporary* method of reducing flammable vapors. Sludge and product trapped in the tank pores will eventually evolve more vapors.

Vapor buildup is a particularly important consideration when a tank is removed and left on a trailer for a period of time or moved a distance to a tank yard. In fact, tanks should be considered to be "time bombs" during all phases of any tank removal operation.

Inerting involves reducing the concentration of oxygen by replacing it with an inert gas such as carbon dioxide or nitrogen. This method eliminates the oxygen element of the fire triangle, leaving the fuel and ignition elements, which cannot, by themselves, support combustion.

During the inerting procedure, carbon dioxide gas is generated through the use of dry ice, which should be distributed evenly in the bottom of the tank. The dry ice releases carbon dioxide as it warms. The amount needed is usually 15 to 20 pounds per 1,000 gallons of tank capacity. For example, a 10,000-gallon tank will require at least 150 pounds of dry ice to be properly inerted. Carbon dioxide inerting takes longer than some other methods because there is no additional air movement in the tank. Tank workers frequently underestimate the amount of dry ice or try to speed up the process. Monitoring the air in the tank is the only way to tell if the tank is safe to handle.

Monitoring is often the place in the vapor control procedure where tank workers take shortcuts. It can't be *emphasized enough, however, that proper air monitoring is the only way to determine if atmospheric hazards exist.*

Nitrogen gas can also be used to inert a tank. Using nitrogen involves placing a hose in the tank and pumping the nitrogen gas into the bottom of the tank. Bonding and grounding of the cylinder nozzle is needed to prevent static buildup. This method may be quicker than using dry ice, but air monitoring is still needed to determine if the oxygen has been sufficiently removed.

As with purging, inerting is a temporary method of making a tank safe. If there are holes in the tank, oxygen may be reintroduced and an explosion could occur. The reintroduction of vapors is a particularly important consideration when a tank is removed and left on a trailer for a period of time or if it must be transported long distances to a tank yard.

"Monitoring the Atmosphere"

(Continued on page 9)

Board Bio; Bill Carver

Bill Carver was appointed to the Board in November 1995 as the certified tank installer representative. He succeeded Gerald LaPointe in that capacity. For the past 5 years Bill owned and operated his business, Bill's Pump and Tank Service in Union, ME. Prior to that he has had 25 years experience in the petroleum and chemical fields.

Bill and his wife Brenda have been married for 31 years and presently live in a farmhouse that was moved to the site 166 years ago in 1832. Bill and Brenda raised German Shepard Dogs for over 25 years. Several of their dogs have gained American Champion titles. In years past they trained several of their dogs in search and rescue techniques, and worked for state and local police departments and the Maine Warden Service.

They also recently acquired a couple of horses that have been doing well in the show.

Vapors at UST Work Sites

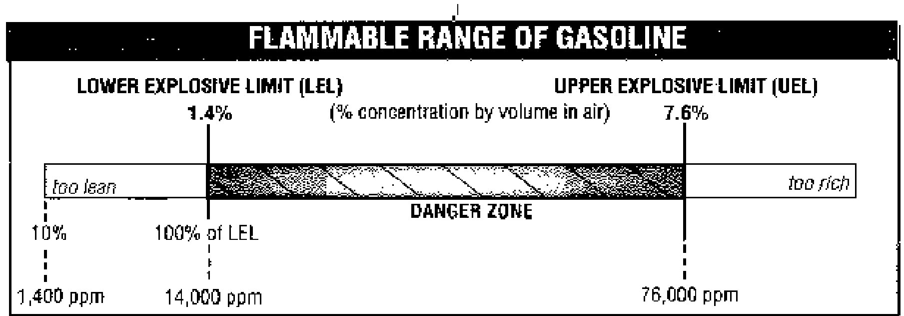
(Continued from page 8)

To determine if the tank is safe to handle and the site is safe for working, the air, both inside and outside the tank, must be monitored. Monitoring is often the place in the vapor control procedure where tank workers take shortcuts. It can't be emphasized enough, however, that proper air monitoring is the only way to determine if atmospheric hazards exist. The concentration of vapor cannot be determined by odor.

There are two types of measurements, depending on whether the tank has been purged or inerted: lower explosive limit (LEL) and oxygen concentration. Both can be measured by using a combustible gas indicator, or detector, which has separate sensors that read oxygen and LEL (and sometimes other substances) independently. Oxygen is measured based on the percent by volume in air. Normal air has approximately 21 percent oxygen. Levels below 11 percent oxygen will not support combustion.

Explosimeters should never be used to measure oxygen when a tank is being inerted. Keep in mind that 11 percent oxygen is needed for an explosimeter to work. If oxygen is reduced because carbon dioxide or nitrogen have been added, the meter will not work properly.

The LEL is based on the flammable range of the substance. For example, gasoline has a flammable range of 1.4 to 7.6 percent by volume in air. The LEL on the combustible gas indicator is based on 0 to 100 percent of the bottom of the flammable range, so for gasoline 10 percent of the LEL would be 0.14 percent by volume in air. This would translate to 1,400 parts of gasoline per 1 million parts of air. According to the OSHA standard, the safe level for tank work is below 20 percent of the LEL. Many contractors do not consider a tank safe to work with until readings are 10 percent of the LEL. The API recommended practice 1604 (1996 edition), *Closure of Underground Petroleum Storage Tanks,* requires readings of 10 percent of the LEL for tank work.



Tank workers are often confused about which meter to use for purging or inerting, oxygen or LEL. The key is to remember which element of the fire triangle is affected. For purging, the fuel concentration is reduced. This means that the air monitoring measurement should test for flammable vapor levels in the tank. The LEL sensor on the combustible gas indicator will test for vapor concentration. This level needs to be below 20 percent. Some contractors will continue purging until the LEL is below 10 percent. If workers must enter the tank, the LEL must be below 10 percent according to the OSHA confined-space entry standard.

Inerting, on the other hand, deals with removing the oxygen element of the fire triangle. Therefore, to determine if the tank is safe, you must measure for oxygen. Most contractors will inert a tank until the oxygen level

(Continued on page 10)

For More Information About Safety During UST Removal...

OSHA Standards

29 CFR 1910.120 *Hazardous Waste Operations and Emergency Response.*

29 CFR *1910.146,Permit-Required Confined Spaces.*

American Petroleum Institute (API) Recommended Practices

Safe Entry and Cleaning of Petroleum Storage Tanks, API 2015 (May 1994). Price:.-$70.

Closure of Underground Storage Tanks, API 1604 (1996). Price. $40.

Order from: American Petroleum Institute, Order Desk, 1220 L Street, N. W., Washington, D.C. 20005. (202) 682-8375.

Tank Closure Without Tears -- An Inspector's Safety Guide (Video and Booklet)

Developed to train inspectors, this video provides a general overview of safety procedures and issues associated with tank closure, including what causes fires and explosions, preparing a safe workplace, preparing the tank, getting rid of flammable vapors, cleaning out sludge, closing in place, and tank disposal. The video is 30 minutes long; the booklet is 20 pages. Price: $35 for video and booklet; $15 for loan; $30 for video; $5 for booklet-

Order from: NE England Environmental Training Center, 2 Fort Road, South Portland, ME 04106. (207) 767-2539.

Vapors

(Continued from page 9)

is 0 to 8 percent by volume in air.

The combustible gas indicator needs to be calibrated every day prior to its use. Between readings on the site, move it away from the vapor hazard area to fresh air in order to clear the instrument. Do not use the combustible gas indicator to test a tank that is full of gasoline because doing so will poison the LEL sensor and damage the instrument.

Although it is not recommended, moving a tank to a remote site in an overrich condition for cleaning is sometimes done. If so, a different meter is needed to determine if the concentration in the tank is above the upper explosive limit (UEL). This meter is a type of combustible gas indicator called a Gascope. It reads the flammable vapor levels in percent by volume. For gasoline, the UEL is 7.6 percent. The safe level for transporting a tank in an overrich condition has not been documented. If done, however, be sure that the tank is at least 15 percent by volume in air prior to transport.

Looking Ahead

Working with underground storage tanks can be dangerous, but there are procedures that can make the process safer. Control of ignition sources, control of flammable vapors, and use of proper air monitoring equipment are important tools for achieving a successful tank removal. Other hazards, such as exposure to chemicals, confined space entry, and accidents associated with careless use of heavy equipment also need to be understood. We'll touch on more of these topics in future issues of *LUSTLine*.

Deborah Roy, MPH, RN, COHN-S, CET, ASP, Safetech Consultants, South Portland, Maine. Reprinted from L.U.S.T.LINE Bulletin 29, June, 1998. Published by New England Interstate Water Pollution Control Commission.

Using ATG's for Leak Detection

Since December 24, 1996 Department regulations allowed existing single walled tanks retrofitted with automatic tank gauges (ATG's) to be exempt from daily inventory and SIA requirements.. The ATG's must be capable of detecting 0.1 gallon per hour (gph) leaks with satisfactory tests conducted at least once every 30 days. The existing piping must be either self monitoring suction, secondarily contained pressurized, or single-walled pressurized with an electronic line leak detector which is capable of detecting a 0.1 gph leak. The installation of an ATG is a retrofit of the tank and a registration amendment needs to be filed with the Department. To ensure the ATG meets the standards and it is setup properly, certain information is required from the owner before the ATG is accepted as the tank's leak detection system. At this time there are only about 10 facilities which have submitted the correct documentation concerning the use of their ATG system.

Common problems have been:

- The ATG is certified as only being able to detect a 0.2 gph leak. They must be able to detect a 0.1 gph leak.
- The ATG was programmed to detect only a 0.2 gph or greater leak. It needs to be programmed to detect a 0.1 gph leak.
- The ATG must have been evaluated as being able to test the size tank in which it is being installed.
- If the tank has single walled pressurized piping then the owner also must have electronic line leak detectors that can detect a 0.1 gph leak.
- A test result from the line leak detector must be submitted.
- The ATG must be operated in accordance with Department regulations and with any limitations listed in the ATG's evaluation

An owner cannot downgrade from secondary containment with continuous interstitial space monitoring to an ATG. If they have continuous interstitial space monitoring then it must be maintained in working order.

On the following page is the informational sheet which owners need to submit to the Department if they have an ATG installed to exempt them from the daily inventory and SIA requirement.

When Air and Water Don't Mix – At Least At DEP.

Recent Department inspections resulted in finding sites where coaxial drop tubes were retrofitted to tanks for Stage I vapor recovery which originally had ball vent float valves installed for overfill protection. A problem with this approach is the ball float valves signal a overfill by shutting off the vent and holding vapors in the tank under pressure. When a coaxial drop tube is used for vapor recovery the vapors are routed back to the truck so the ball float is inoperative and the tank can overfill. If overfill protection, required on tanks installed since 1991, has been defeated by the installation of a drop tube, another method of overfill protection must be installed. Other possibilities would be equipment that will automatically shut off flow into the tank, such as a flapper valve in the drop tube when the tank is no more than 95 percent full. Another option is an electronic alarm which will alert the transfer operator when the tank is no more than 90 percent full by triggering a high-level audible alarm.

In a properly designed two point system, this problem does not occur because the vent float valve is in line with the air flow back to the tank truck.

Ted Scharf, Environmental Specialist, Maine Department of Environmental Protection, Bureau of Remediation and Waste Management, Division of Oil and Hazardous Waste Facility Regulation.

Requirements for using an Automatic Tank Gauge

If you wish to install and use an Automatic Tank Gauge (ATG) in order to meet MeDEP leak detection requirements for singlewalled underground oil storage tanks, then the following requirements must be met. Tanks which meet these requirements are exempt from keeping daily product inventory and doing an annual statistical inventory analysis.

The ATG system must be installed as a permanent component of the facility.
The ATG must print or record test results at least once every 30 days.
ATG systems must be operated with a back-up system to preserve test data in the event of a power outage.
Tests must be conducted with the tank 60 percent or more full.
ATG system must monitor the tank bottom for water level gains of more than 1/2 inch.
The associated product piping must be either a self-monitoring suction system, have secondary containment with interstitial space monitoring, or be equipped with an electronic line leak detector capable of detecting a 0.1 gal per hour leak.
Tests must be conducted in the same manner as they were evaluated.

The monthly test record must include the following information:
Test date
Tank size and product stored
The test's leak detection threshold
The date and time of the last prior product delivery
Product level
Test length
Test results (Pass or Fail)

Please complete and submit the following form to the MeDEP as a change to your registration. After review the Department will send you an updated registration certificate.
- -

Facility Name ____ Registration Number __________

Address ____

Tank Number _________ Size ____________ Product stored?____________________________

ATG Manufacturer ______________ Model ______________

Installer name _____________________________ Installer number __________

*****Please attach a copy of the set up report and a tank test report (including 0.1gph line leak test if applicable) from the ATG.** **(June 1997)**

Automatic Line Leak Detectors

(Continued from page 5)

pumps that feature automatic adjustment of pump motor speed according to the number of nozzles that are open. This allows the pump to operate more efficiently and to rapidly fuel a greater number of customers. At least one manufacturer of these intelligent pumps monitors the pressure in the line to determine the pump motor speed. This same pressure monitor is then used after the pump is shut off to look for pressure drops in the piping that may indicate a leak. Leak detection for pressurized piping has at last become an integral part of the pump design rather than an afterthought. It's about time.

Marcel Moreau, Marcel Moreau Associates, Portland, Maine.. Reprinted from L.U.S.T.LINE Bulletin 29, June, 1998. Published by New England Interstate Water Pollution Control Commission.

Phyllis Pimentel

Mrs. Pimentel's husband, Phil, was also the first chairman of the Board of Underground Storage Tank Installers and holds Tank Installer Certificate 001.

BOSTON - Phyllis Lee (Brown) Pimentel, 56, died Wednesday, Oct. 14, 1998, at New England Medical Center in Boston after a long courageous battle with breast cancer.

Mrs. Pimentel was raised and educated in Lynn, Mass., and has resided in Augusta since 1971. She was a graduate of Green Mountain College in Vermont. She and her husband owned and operated PIM Enterprises, a training and consultant company in the petroleum storage industry. Mrs. Pimentel also was the operator of Avis Car Rental at the Augusta Airport up until 10 years ago. Until her illness, Mrs. Pimentel and her husband had been operating Airport Automotive Co. in Augusta. She was an avid boater and was, with her husband, the owner of the cruiser "Tropic Night ," in Boothbay Harbor. She was a member of St. Mark's Episcopal Church in Augusta and had served on the Vestry of the Church.

She is survived by her husband, Philip L. Pimentel, of Augusta; her parents, of South Carolina; one son, Michael R. Pimentel, of Framingham, Mass; one daughter, Dana L. Pimentel, of Atlanta, Ga.; two sisters, Judith Chesney, of Georgia, and Evelyn Garnett, of Maine; several nieces and nephews.

The Maine Installer

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